Stakeholder Comment Matrix – June 25, 2020

Participant-Related Costs for DFOs (Substation Fraction) and DFO Cost Flow-Through
Technical Session 3

Period of Comment: June 25, 2020 through July 17, 2020		**Contact:**	[redacted]
Comments From:	Denis Forest Consulting Inc.	**Phone:**	[redacted]
Date:	July 17,2020	**Email**:	[redacted]

Instructions:

1. Please fill out the section above as indicated.
2. Please respond to the questions below and provide your specific comments.
3. **Please submit one completed evaluation per organization.**
4. Email your completed comment matrix to tariffdesign@aeso.ca by **July 17, 2020**.

The AESO is seeking comments from Stakeholders with regard to the following matters:

	Questions	Stakeholder Comments
1.	Please comment on Technical Session 3 hosted on June 25, 2020. Was the session valuable? Was there something the AESO could have done to make the session more helpful?	Session 3 was valuable in so far as revealing the AESO's intentions and participants' reactions. The AESO's original proposal to the AUC for Technical Sessions included the following objectives: c) The AESO would work to develop a joint proposal with DFOs and DCGs regarding a path forward, based on the views expressed by parties at the technical session(s). d) A joint proposal, if achieved, or individual proposals regarding the attribution and flowthrough of transmission costs to DCGs would then be filed in the consolidated proceeding for consideration and determination by the Commission. In Session 3 we learned that the AESO intends to file a proposal developed solely by the AESO, which, based on participant reaction during Session 3, is not supported by DFOs nor DCGs. This will not fulfill the stated objectives nor meet the AUC's expectations for the Technical Sessions. As a result, it seems that much work which could have been done during the Technical Sessions will be pushed into the consolidated R&V proceeding with the associated need for additional resources and time by the AUC and participants which the Technical Sessions were intended to minimize. It's possible that the AESO proceeded in this way in the belief that the need for speed trumped other considerations. However, the AESO's proposal does not provide an expeditious resolution to this issue. With this approach, the issue of DCG responsibility for transmission system costs is merely shifted to another arena, creating further delay and uncertainty regarding DCG connections costs and DFO responsibilities. The Technical Sessions were intended to 1. provide participants with a good understanding of the Substation Fraction/ Construction Contribution Decision (**SSF/CCD**) process and the breakdowns which resulted in the R&V filings; 2. develop, understand and debate alternative solutions to the problem at hand; and 3. support the finalization of any generally supported alternatives for AUC consideration. At this stage it seems that the Technical Sessions will not meet any of these three goals.

2.	Please comment on your level of support for the AESO's revised proposal and the level to which AESO's revised proposal supports the principles (as developed through this stakeholder engagement). Please be as specific as possible.	The AESO's revised proposal is ingenious and creative. The proposal involves two elements: 1. setting the SSF equal to 1 for DFO projects; i.e. using exception handling to remove supply-related considerations in DFO-related CCDs; 2. deferring the question to the DFO arena of whether or not DCGs should pay a "transmission system access fee" in addition to their connection-related costs and, if the consensus is to do so, determining how that fee should be calculated. Presumably these questions would be addressed as part of the Distribution System Inquiry (**DSI**) and subsequent Distribution Tariff applications. In presenting its case for this proposal the AESO • maintains that what the DFOs charge DCGs is a DFO issue, hence the two-point approach removing DCG visibility from AESO cost allocation considerations and tossing the issue of DCG responsibility for transmission system costs over the fence; • points out that this aligns with the AESO's goal of "simplifying and streamlining" the AESO tariff; • uses the unfolding DSI and the revolution occurring with Distributed Energy Resources (**DER**) as reasons to not rush to finalize a solution on this issue. These specious arguments seem an effort to justify abandoning the responsibility for a contentious transmission system administration issue, a broken process, which the AESO would rather partially abandon than fix. At Denis Forest Consulting Inc. we have worked with the SSF/CCD process for nearly two decades and have overseen or developed over 1000 CCDs in our various staff and consulting roles over that time. The established AESO cost allocation process is based on the substation fraction approach and calculated via the Construction Contribution Decision template. The use of the SSF was introduced, debated and approved in the early years of deregulation, but did not foresee the significant development of local electricity supply by DCGs. Since 2017, the emerging ineffectiveness of the existing process for determining transmission system cost allocations in DFO-DCG situations has resulted in these Technical Sessions. However, we believe that the CCD is an important, well-established and generally functional AESO administrative tool. The root problems of the process breakdown are simple. Also, relatively simple is the means to address these unforeseen and inappropriate results. See page 9. We believe that the CCD template can be adjusted and continue to serve our industry well. Looking at the AESO's proposal, what does it mean to "Set substation fraction = 1 for DFO substations where there is only D-connected load"? Presumably this means the Demand-related substation fraction on Attachment A2 would be set to 1 and the Supply-related substation fraction would be set to 0, rather than having these values determined by a calculation on Attachment A3. As a result, the CCD would ignore any STS-related consequences for DFO-related CCDs for transmission system connections/upgrades at PODs with only distribution-connected load (vs. Section 101 or ISD-related load and ignoring DCG-driven STS contracts). With this approach, applicable investment would be calculated and any Construction Contribution would be deemed fully Demand-related. This concept impacts CCDs prepared in cases

		a) where a DFO load-driven upgrade occurs at a substation where a DCG is already connected and an STS contract exists (e.g. AESO project 1782) b) where a previously (in the last 20 years) DFO load-driven substation upgrade subsequently adds an STS contract in relation to a DCG connection (e.g. AESO project 1495) c) of Behind-the-Fence (**BTF**) connections for DCGs (e.g. AESO project 1608) With this approach the AESO would effectively ignore any transmission system-related costs caused by DCG presence or attributable to DCGs. In the first two examples this exception handling has the fortuitous result of simulating a causation analysis. In BTF cases, it ignores participant costs as defined by AESO Tariff Section 8 Term 3 (2) (i). These costs have generally been ignored in CCDs but included in the DFO's connection cost to the DCG, i.e. the DFO contracts directly with the TFO for the necessary transmission system work such as transfer trips, etc. As a result, since the AESO is not mediating the TFO work, the AESO has been ignoring these costs. The first CCD provided in document 22942-X0539 from Proceeding 22942 is a rare example of the AESO properly including such costs in a CCD and correctly determining a Substation Fraction of 1 for Supply-related and 0 for Demand-related. In addition to the three cases presented above, potential DCG situations exist in which setting Demand-related SSFs = 1 and Supply-related SSFs = 0 would not be appropriate. From this analysis, we see that the first element of the AESO's proposal, exception handling for DFO CCDs, is intended to remove the determination of DCG responsibility for transmission costs from the AESO. This has the potential for complexities and unforeseen consequences. Fixing the CCD problems would be preferable to introducing new practices and potential problems. The second element of the AESO's proposal, pushing the issue onto DFOs, creates further delay and uncertainty for DCGs and DFOs regarding the allocation of transmission system costs to DCGs. In Session 3 the AESO admitted that the revised proposal does not satisfy the Technical Session principles (as developed through this stakeholder engagement) on which an acceptable solution was to be based. Quite true. This proposal • does not provide a speedy and easily understood and implemented solution to the matter of connection costs for DCGs; • leaves the issue of a potential transmission system access fee for DCGs unresolved thereby creating ongoing uncertainty regarding connection cost for DCGs and administrative practices for DFOs; • ignores TCG/DCG parity; • leaves the issue of cross-subsidization for future analysis and resolution;

		• will introduce new (and arguably unnecessary) elements in the AESO's administration of transmission cost allocation (i.e. exception handling for DFO-driven projects) and possibly in the cost allocation and administration practices of DFOs (i.e. adding a transmission system access fee for DCG connections). Besides not satisfying these principles, the AESO's new proposal does not address the very reason for the consolidated proceeding and Technical Sessions. That reason is simple and seems to have been accepted by all of the participants in the Technical Sessions, including the AESO: inappropriate supply-related costs are calculated in CCDs in cases where DFOs request transmission system upgrades at substations which supply, or subsequently connect, DCGs. From participant comments during the Technical Sessions and in Session feedback, it seems that the underlying reasons for this problem have not adequately explored or understood. Why are supply-related costs being inappropriately determined? Based on our experience with and understanding of the SSF/CCD process, there are **two root causes** for the inappropriate cost allocations in DFO-DCG situations. 1. **DFOs are** wire service providers, **not participants** – except in Alberta's transmission-centric system whereby any entity connected to the transmission system is defined as a participant. (The term "participant" should logically be based on energy market status, i.e. an electricity producer or consumer.) Given Alberta's definition of "participant", when a System Access Service Request (**SASR**) is submitted by a DFO, the CCD methodology must look *beyond* the DFO to identify the true "participant" driver – load, supply, or a combination thereof – for the requested transmission system upgrade and associated costs. 2. The approved substation-fraction approach determines **causation based on DTS/STS contract capacities and duration** which **is** definitely, and undeniably, **not appropriate** in most DFO-DCG situations. Unfortunately, in Proceeding 22942 when challenged on the cost allocations in DFO-DCG situations resulting from the long-standing approved cost allocation process, the AESO defended the results of the process with three arguments - which explains why this issue has proceeded to this illogical point. 1. The AESO initiated a "fairness" argument claiming that it was not fair for DCGs to benefit from the use of facilities paid for by load, i.e. shared use justified shared cost. 2. The AESO claimed that upgrades (generally clearly requested by DFOs for the needs of distribution load customers) produced benefits for the DCG, therefore it was appropriate for the DCG to contribute to the cost of the upgrades. 3. As the upgrades were requested by DFOs, and the CCDs were issued to DFOs, the allocation of the resulting Construction Contribution between distribution system customers was actually a DFO responsibility. "*Who better than the DFO to decide who should pay for the DFO's required transmission system upgrade projects?"* seemed to make sense. This issue was compounded by the observation that DFOs had not adjusted any Construction Contributions based on "supply-related" amounts in CCDs. However, this reflected the DFOs awaiting regulatory direction regarding the AESO's evolving and controversial handling of DFO-DCG cost allocations rather than a deliberate decision and process to deal with supply-related costs at the DFO level.)

Superficially reasonable, presented by the "transmission system authority", and insufficiently analyzed and challenged, these flawed arguments carried the day in Proceeding 22942.

In addition to these three flawed arguments, the AESO also employed a fourth approach to deal with the issue. The long-standing CCD methodology was surreptitiously altered to base upgrade (i.e. incremental) costs on full contract capacity rather than on incremental contract capacity, further disconnecting allocation from causation. This seems to have been intended to reduce the magnitude of costs being unjustifiably shifted from load to DCGs. This CCD template alteration was also quietly formalized in the 2019 CCD template, thereby applying the causation disconnect for all CCD situations.

As mentioned, Decision 22942-D02-2019 supported continued use of the existing cost allocation process. The injustice of cost allocations to the non-causal DCGs and the impending destructive impact of these practices on DCG development in Alberta led to the R&Vs which prompted these Technical Sessions.

At Denis Forest Consulting we believe that the "Principles" identified to consider in developing a solution to this issue missed an important principle, contributing to a warped sense of the concept of "fair". The missing principle is **compliance**: i.e. the solution to this process breakdown must comply with Alberta laws, regulations and policy: the HEEAC, the EUA, the TReg and the TDP. These are the basis for transmission and distribution tariffs. These define the rules and practices for participant cost responsibilities and allocation in Alberta.

From these documents the participant cost responsibility concept can be simply summarized as:

- all participants, load and generation, pay for the costs related to their connection to the existing wires system. Load customers may benefit from investment, the cost of which is recovered through the ongoing monthly load customer's system access service charges. Generation customers must pay the full cost of connection, i.e. no investment is available. There is no capital recovery component in generators' monthly system access service charges. (The GUOC is not a means whereby generators pay for the general wires system but a performance bond to ensure the transmission system can be planned and developed based on reasonable generator performance expectations.)
- the general cost of the wires (bulk and regional system costs, planning, operations and maintenance, and administration costs for associated agencies) is born by load customers (as reflected in transmission and distribution investment terms and rates).

Based on these foundational understandings, and as applied by the AESO for decades, a transmission-connected generator (TCG) pays for the cost to connect to the transmission system. This is for the transmission facilities to tie the generator site to the nearest set of transmission wires including any required upgrades at affected substations, upstream conductor upgrades if necessary for the anticipated current levels, and associated protection (including telecommunication) costs. This may be as little as the cost of a breaker at a substation adjacent to the generator site, or as much as the cost of a new substation, miles of transmission line, high side breakers, and the protection and telecommunication upgrades required to safely and effectively connect the new generator to the transmission system. This may include cost sharing for facilities installed by others which are an integral part of the generator's connection requirements. This <u>does not</u> include paying for the cost of existing transmission facilities beyond those related to the generator's connection – even if the generator's output will clearly flow over those facilities and wires to reach load customers supplied by that generator under various system conditions. This <u>definitely does not</u> include any contribution to cover the cost of the distribution systems onto which the generator's output will flow to reach distribution-connected load customers. To keep it simple, a (typically large) transmission-connected generator pays the cost to connect to the transmission system. This could be less than $1M, or $5M, or much more, depending on generator size and location. As a very general ballpark example, a 200 MW generator, could pay $4M in connection cost. This works out to $20,000 per MW.

There is absolutely no reason, nor arguments, laws, regulations or policies, which indicate that distribution-connected generators are to be treated any differently. To keep it simple, a (typically small, i.e. limited by feeder capacity) DCG should pay the cost to connect to the distribution system. If the DCG connection involves transmission-related upgrades, e.g. transfer trips, breaker adds, transformer upgrades or additions, or line upgrades, those costs are included in the DCG's connection cost by the DFO. Considering distribution and transmission system-related connection costs, a 25 MW DCG (which would require splitting its supply across two distribution feeders) can face a ballpark combined T and D cost, provided by the DFO, of $500,000 to connect the DCG to the existing wires system. This amounts to $20,000 per MW.

There are numerous variables involved so that the sample values given can only serve as general averages, but these figures indicate a basic sense of parity on connection cost for TCG and DCG. Larger generators have economies of scale; smaller generators have more modest connection requirements. (Like the cost to air condition a house, paid for by the homeowner, vs. an office building, paid for by all of the tenants, resulting in equitable costs per benefitting party).

However, if a DCG connects to a substation which, in the recent past (less than 20 years) or in the future, has been or will be upgraded to meet the needs of load customers, what possible rationale justifies putting those upgrade costs on the DCG? This would violate Alberta's laws, regulations and policies, and the economic principle of causation, yet, with the existing SSF/CCD process, this is the problem which we are addressing with these Technical Sessions.

To address the AESO's four attempts at misdirection on this issue:

1. The concept of sharing in the cost of shared facilities.

   "Fairness" must be defined within the context of compliance. As per Alberta policies, laws, regulations and tariffs, generation pays the costs related to their connection to the wires, not for facilities beyond the point of connection over which, under various system load conditions, the generator's supply may flow. The TDP recognized that the wires system (transmission and distribution) exists to deliver electricity to load customers. If there were no load customers, there would be no need for wires. Hence, load customers pay for the wires system. Generators pay only to connect to the wires in order to get electricity into the delivery pipeline provided by the transmission and distribution systems.

   It is true that two parties sharing the use of a transformer seems to justify their sharing of the cost of that transformer. And in the case of two load customers, shared use supports shared cost. The transformer will be sized based on the cumulative load needs of both customers. However, except for rare cases, a distribution source transformer is sized for, and driven by, the needs of the distribution load. Adding a DCG does not necessitate adding transformation capacity. From a distribution system planning perspective, as a DCG is often not a predictable, consistent source of electricity, the transformer must be sized to meet the needs of the distribution load ***as if*** the DCG were not present. So, the transformer is needed, sized and installed to serve load needs and is

		not part of a DCG's connection requirement. And if, as in the case of AESO Project #1495, a second transformer is needed for distribution load reliability reasons, it is not in any way driven by, or needed by, a 29 MW DCG (i.e. the Bull Creek Windfarm) whose supply capacity is more than adequately served by the existing 47 MVA transformer at the Hayter 277S substation. From a physics perspective, the concept of generation "sharing" in the use of a distribution source transformer is illogical. Unlike two load customers each sharing in, and loading, a substation transformer, a generator causes reverse power flow thus reducing the load on a substation transformer. I.e. unlike two loads which result in an additive load on transmission facilities, a DCG on a feeder fed from a distribution POD results in a subtractive (reduced) load on the transmission facilities when the DCG is operating. 2. The concept of DCGs receiving user benefits from load-driven upgrades. Consider: if my neighbor plants an apple tree adjacent to our common property line for privacy, shade and apples, his argument that I should contribute to the cost of the tree because I also get privacy, shade and apples does not constitute any grounds for my bearing any cost for his decision to buy and plant that tree. Besides, the tree blocks my views, my sunlight, and leaves rotten apples all over my lawn. As a quantitative assessment of disparity between benefits derived, consider the following. Load customers need a high level of reliability. Because of the increasing personal, business, industrial and institutional reliance on electronics and a high level of power security, or a chicken farm at risk of freezing, or an industrial plant which may face weeks of clean-up, recommissioning and environmental consequences from an unplanned short-term loss of power, the AUC has supported DFO requests for transmission system facilities which provide a high level of distribution service reliability, as required by the DFO's mandated service obligations. However, as well presented by BluEarth's Laura Dahlke in Session 1, the incremental value (from a lost income perspective) to a DCG of moving from 98% to 99.5% reliability might be $50,000 – far from a $2M+ contribution for the addition of a second transformer, or an ~$9M contribution for adding a transmission line at the distribution POD serving the Bull Creek Windfarm facilities. (If the DCG had requested the upgrades, maybe it would make sense to allocate $50,000 to the DCG based on value derived, **but the DCG did not request, did not need, and had no say in the upgrade. They are just being told to pay for their neighbor's apple tree.)** Finally, an argument was made that DCGs rely on the system stability and market access provided by the transmission system and this justifies sliding transmission system costs into DCGs' connection costs. **IF** Bull Creek had commenced operations in August 2015 rather than December 2015, and **IF** Fortis had been required to execute a minimal DTS contract increase (0.1 MW) to create a minimal causation signal, the resultant CCD would not have allocated any supply-related cost for project 1495, yet the DCG would have had the system stability and market access benefits anyway. Clearly, those are not the determinants or justification for cost allocation. 3. DCG cost allocation is the responsibility of the DFO. In any case in which a CCD issued by the AESO involves investment, a DFO is not free to vary from the AESO's assessment of load and supply cost allocations due to the investment erosion caused by the CCDs determination of a supply-related amount.

		Beyond that basic factor, should DFOs decide to apply their own cost allocation decisions subsequent to AESO-issued CCDs, the two potential resultant scenarios would trigger the very regulatory question we currently face: a) if the DFO followed the AESO's load/supply split we would have the problem and challenges which resulted in these Technical Sessions, or b) if the DFO attempted to allocate load-driven costs to its load customers despite a supply-related value on the AESO CCD, participants would challenge the practice as pushing DCG costs onto load. DFOs and DCGs are the victims, not the cause, of this issue. The problem at hand is the faulty function of the AESO's SSF/CCD process, not the DFO's inability to rectify inappropriate AESO-generated cost allocations. This is a transmission system responsibility and administration issue. The problem cannot practically or jurisdictionally be pushed downstream to the DFOs. 4. Altering the long-standing cost allocation practice. The alteration to the longstanding CCD template involved basing the SSF for cost allocation on contract capacities rather than incremental capacities (see Attachment A3 of the CCD template.) Presumably this was done to give DCGs a break as basing upgrade cost allocation on contract capacities will usually, but not always, result in a lower supply-related allocation. However, perverse and undesirable cost allocations can occur in some load/supply scenarios. As displayed by the 10 CCDs issued by the AESO, provided by Fortis in Proceeding 22942 (see Document 22942-X0539), related to Hayter 277S upgrade projects 1495 and 1782 and the Bull Creek Windfarm, demonstrating the errors, delays, and various approaches to cost allocations from 2015 to 2018, the ultimate use of altered CCDs is noteworthy. Furthermore, in reviewing the 187 distinct CCDs filed by Fortis for the 2015, 2016 and 2017 Capital Tracker True-ups, it is apparent that the AESO altered various posted CCD templates without consultation, notification or explanation, failed to provide the relevant CCD Attachment showing the altered calculation in at least one case, and, in response to an Information Request in Proceeding 22942 requesting a sample CCD template and a sample CCD calculation, provided an unaltered CCD template but an altered sample CCD calculation. If contract capacity is the causation determinant, appropriate allocation of costs must match incremental cost to incremental capacity. (An argument could be made justifying upgrade cost allocation on full contract capacity on the basis of benefits derived, however, as per item 2 above, this is an invalid approach as unrequested and imputed benefits do not justify cost allocation.) From the review of the AESO's flawed efforts to justify or modify the existing cost allocation practices, one must move to a root problem approach in order to address the issue at hand. As presented above on page 5, there are two root causes to the cost allocation process breakdown. Happily, **the solution** is not complicated. • Identify the causative customer group on DFO CCDs.

Recognize that DFOs are not simple participants but rather wire service providers, like TFOs, with two customer groups – load and supply – each group having distinctive service requirements. Add a step to the CCD process to look past the DFO **on DFO-submitted SASRs** to **identify the causative customer group**.

- Include a technical evaluation of causation in the FS.

  Causation can be correctly established by AESO engineering staff; this is a technical, not a commercial, function. The Functional Specification (**FS**) document produced by the AESO in Stage 3 of the Connection Process defines system vs. participant-related costs. **As part of the FS, the participant-related costs can be further defined as load or supply-related.** This information will feed into the TFOs Proposal to Provide Service (**PPS**). The PPS includes a +20/-10% cost estimate used in the Stage 3 CCD, which is produced prior to customer commitment. This will provide cost certainty for the DFO and affected participants prior to commitment. (Once this practice is established, DCGs and DFOs can also fairly confidently estimate DCG costs during preliminary discussions and early stage application documents.)

By employing existing AESO practices, tools and staff, this solution addresses the root problems in the SSF/CCD process which has produced inappropriate cost allocations in DFO-DCG situations.

This solution keeps the responsibility for transmission cost administration with the AESO rather than dumping it onto DFOs. (See blue text below for additional reasons why pushing this issue to DFOs is not appropriate.)

This solution

- satisfies the guiding principles of fair, compliant, and easy to understand;
- should be quick to implement (with minimal, if any, tariff revision or need for regulatory involvement);
- avoids delays and uncertainty awaiting DSI developments; in fact, it provides a good foundation of cost allocation principles and practices to carry into future utility sector developments;
- provides cost certainty and stability for DCGs and DFOs, both prior to commitment and thereafter;
- supports connection cost parity for TCG and DCG;
- provides effective price signals for generators enabling developers to determine location and generation type and scale based on fair and established connection cost practices;
- does not result in cross-subsidization, i.e. DCGs will not be paying for load-driven transmission system upgrades. (An important point which is not generally understood based on participant comments in the Sessions.)
- applied retro-actively, this solution addresses prior faulty CCD outcomes;
- applied going forward, it eliminates regulatory and participant resource cost, waste and churn (as occurred in Proceeding 23393 where the conflicting needs of load and supply drove a DCG developer to challenge the need for a load-driven project simply because a significant portion of the project cost would have been allocated to the DCG when the DCG had no need for, nor significant benefit from, the requested upgrade);

- supports optimal utility system costs and operation based on recognizing that the cost of electricity for load customers will be lower due to preferential financing for regulated DFOs and TFOs carrying load-driven capital costs in their rate base versus DCGs required to price load-driven transmission system costs into their electricity sale costs;
- by enabling DCG development in Alberta this approach also promotes electricity cost suppression by
  - the price-taking bid practices of renewable and opportunistic energy DCG's, and
  - DCGs providing local supply thus reducing system losses costs;
- provides the optimal value for Albertans in that DCG development provides beneficial economic and environmental impacts for Alberta;

Additional reasons why the debate about DCGs paying "connection costs plus a fee" should not be pushed into the DFO arena.

If this proceeds as the AESO proposes, i.e. with the AESO eliminating consideration of load vs. supply-related costs for DFOs (i.e. SSF=1 for DFOs) and pushing the issue of an extra "transmission system access fee" onto DFOs, besides

- Not addressing the root problem with a simple, quick fix, and
- Introducing new administrative practices for the AESO (exception SSF handling of DFOs) and potentially a new DCG fee by DFOs with the possibility of unforeseen and undesirable future consequences (e.g. CP12)

it raises the following challenges and uncertainties.

- When will DFOs raise and decide the issue of a potential "transmission system access fee"? In one year with their next tariff application? Upon completion of the DSI? Are we heading for the development of a "Distribution Development Policy" and a "DReg"? Where does causation fit in? Will it be five years before debate is completed on whether such a fee should be applied, should be part of the DFO tariff, and a mechanism is defined to set and administer the fee? How much additional, unnecessary time and resource investment will be required of participants and regulators when the opportunity, resources and regulatory direction exist to address and resolve this now?
- Will the potential DFO-managed transmission system access fee for DCGs be retro-active? Or should DCGs rush to connect hoping that there will be no such charge until one is collectively debated, designed, approved and implemented on a go-forward basis?
- Will all DFOs treat DCGs similarly? Will DCGs face different connection cost practices and premiums depending on which DFO they are dealing with? Or where they connect in a DFO's territory?

	Please comment on any outstanding risks or issues you see with the AESO's revised proposal. Please be as specific as possible.	The issue with the AESO's revised proposal is that it does not solve the root problem, i.e. a fault in the SSF/CCD process. The risk is that it leaves the debate and determination of a potential Transmission System Access Fee for DCGs to an undetermined future date and an unpredictable outcome with potential retro-active cost allocations of uncertain magnitude.
	Please provide any further comments you may have on next steps regarding regulatory process and implementation. Please be as specific as possible.	We believe that the AESO's decision to proceed with their revised approach will result in a protracted consolidated proceeding in order to • achieve a clear, detailed understanding of the root problem, • produce a fulsome discussion of potential solutions to the root problem, and • result in an appropriate and robust regulatory decision. Most of this process and result could have been achieved by discussion, debate and consensus in the Technical Sessions. The resource and cost implications of the AESO's proposed approach, and the delays and uncertainty for DCGs and DFOs will be borne by the electricity consumers, businesses and citizens of Alberta.
	Additional comments	The AESO's commitment to invite, accept and share participant input and feedback on the sessions is appreciated.

Thank you for your input. Please email your comments to: tariffdesign@aeso.ca.